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August 9, 2005

BY OVERNIGHT DELIVERY AND E-FILE

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 05-27

Dear Ms. Cottrell:

Enclosed for filing, on behalf of Bay State Gas Company ("Bay State"), please find Bay State's responses to the following Record Requests:

From the Department:

RR-DTE-103 (Amended) RR-DTE-113 RR-DTE-122

Please do not hesitate to telephone me with any questions whatsoever.

Very truly yours,

Patricia M. French

cc: Per Ground Rules Memorandum issued June 13, 2005:

Paul E. Osborne, Assistant Director – Rates and Rev. Requirements Div. (1 copy)
A. John Sullivan, Rates and Rev. Requirements Div. (4 copies)
Andreas Thanos, Assistant Director, Gas Division (1 copy)
Alexander Cochis, Assistant Attorney General (4 copies)
Service List (1 electronic copy)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 9, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

RR-DTE-103 (Amended): In addition to the previous seven requested changes to the proposed cost of gas adjustment tariff, M.D.T.E. No.63, please do the following:

(A) through (G) are found in the original record request.
(H) At page 6 of 35 of the red-lined version, in the only formula on the page, change the variable "PSpx" from superscript to regular script.
(I) At page 7 of 35 of the red-lined version, in the first formula on the page, eliminate the variable "STRANDp superscript x".
(J) At page 10 of 35 of the red-lined version, eliminate the variable ""SBCp superscript x" from the formula to calculate "Cp superscript x".
(K) At page 13 of 35 of the red-lined version, replace "and" with "-" (the minus sign) in the formula for GAFop superscript x.
(L) At page 14 of 35 of the red-lined version, eliminate the definition for "Lbop".
(M) At page 16 of 35 of the red-lined version, define the variables "BOop" and "BOvol" in the definition for "BOao superscript x"

Response: Please see the attached (further) revised proposed Cost of Gas Adjustment Clause, M.D.T.E. No. 36, tariff with the requested revisions, both in a clean (Attachment RR-DTE-103 (Amended) Clean) and red-lined strikeout (Attachment RR-DTE-103 (Amended) Red-Lined) version.

BAY STATE GAS COMPANY

M.D.T.E. No. 36
Cancels M.D.T.E. No. 3
Page 1 of 21

COST OF GAS ADJUSTMENT CLAUSE

Section

1.0 Purpose

The purpose of this clause is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company"), subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on a semiannual basis, its rates for firm gas sales service in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchase gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit all supplier refunds and the margins above the Annual Threshold associated with capacity credits from non-core sales and transportation, interruptible sales and transportation and capacity release sales to firm ratepayers.

2.0 Applicability

This Cost of Gas Adjustment ("CGAC") shall be applicable to Bay State and all firm gas sales made by Bay State, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the Department. See Section 13.0, "Other Rules."

COST OF GAS ADJUSTMENT CLAUSE

3.0 Cost of Firm Gas Allowable for CGAC

All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the CGAC. Any costs recovered through application of the CGAC shall be identified and explained fully in the semi-annual filings outlined in Section 12.0.

4.0 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

5.0 Definitions

The following terms shall be defined in this section, unless the context requires otherwise.

(1) **Annual Threshhold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.

(2) **Bad Debt Expense -** is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.

(3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.

(4) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.

(5) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal*.

(6) **Economic Benefit** - The difference between the revenues received and the marginal cost determined to serve non-core customers.

(7) **Interruptible Sales Margins** - The economic benefit derived from the interruptible sale of gas downstream of the Company's distribution system.

COST OF GAS ADJUSTMENT CLAUSE

(8) **Inventory Finance Charges** - As incurred or billed each month for the carrying costs on the value of the balance of inventory gas for the respective month. The total charges shall represent an accumulation of the projected monthly charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate of the Company or through a trust or other financing vehicle.

(9) **Local Production Capacity and Storage Costs** - Include the ancillary supply costs of providing local manufactured gas, gas dispatching, gas acquisition, and miscellaneous A&G costs as determined in the Company's most recent rate proceeding. Per this proceeding, $7,401,961 shall be allocated to the peak period and $325,300 shall be allocated to the off-peak period.

(10) **SMBA** – Simplified Market Based Allocation Method - Used in determining the allocation of gas costs among High and Low Load Factor classes.

(11) **Non-Core Commodity Costs** - The commodity cost of gas assigned to non-core sales to which the GAF is not applied. Non-core sales include sales made under interruptible contracts, non-core contracts and off-system sales.

(12) **Non-Core Sales Margins** - The economic benefit derived from non-core transactions to which the GAF is not applied, including interruptible sales and other non-core sales generated from the use of the Company's Gas Supply resource portfolio.

(13) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

(14) **Number of Days Lag** - The number of days lag to calculate the purchased gas working capital requirement as approved by the Department.

(15) **Off-Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the off-peak season.

(16) **Off-Peak Demand** - Unless otherwise approved by the Department, the gas supply demand and transmission capacity assigned by the Company to serve firm load in the off-peak season.

(17) **Off-Peak Period** - May through October.

(18) **Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the peak season.

(19) **Peak Demand** - Unless otherwise approved by the Department, gas supply demand, peaking demands, storage and transmission capacity assigned by the Company to service firm load in the peak season.

(20) **Peak Period** - November through April.

(21) **PR Allocator** - The percentage allocated for the portion of annual capacity charges assigned to the seasons calculated in each CGA filing.

(22) **Pretax Weighted Cost of Capital** - The result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one, minus the currently effective combined tax rate, plus the weighted cost of debt.

COST OF GAS ADJUSTMENT CLAUSE

(23) **Purchased Gas Working Capital** - The allowable working capital derived from peak and off-peak, demand and commodity related costs.
(24) **Tax Rate** is the combined State and Federal income tax rate.

(25) **Weighted Cost of Capital** is the weighted cost of capital as set in the Company's most recent base rate case.
(26) **Weighted Cost of Debt** is the weighted cost of debt as set in the Company's most recent base rate case.

6.0 Gas Adjustment Factor (GAF) Formula

The Gas Adjustment Factor (GAF) Formula shall be computed on a semiannual basis using forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

A separate seasonal GAF will be computed for the combined Low Load Factor classes namely Rates R-3, R-4, G-40, G-41, G-42 and G-43; and for the combined High Load Factor classes namely Rates R-1, R-2, OL, G-50, G-51, G-52 and G-53. The calculation of each seasonal GAF utilizes information periodically established by the DTE. The table below lists the following approved cost factors as approved in D.T.E. 05-27:

Local Production & Storage Cost	$7,727,261
LNG/LPG Production Cost included above	$5,258,855
Bad Debt Expense Percentage	2.17%

Peak GAF Formula

The Peak GAF shall be comprised of a peak demand factor (DFp), a peak commodity factor (CFp), a peak production and storage demand factor (PSp), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF) defined in Section 15.00, for the Company's High and Low Load Factor classes and calculated at the beginning of the peak season according to the following formula:

$$GAFp^x = DFp^x + PSpx + CFp^x + BDF - R1 - R2$$

COST OF GAS ADJUSTMENT CLAUSE

Peak Demand Factor (DFp) Formula

$$DFp^x = \frac{Dp^x - NCSMp^x}{P : Sales^x} + RFpd + WCFpd$$

and:

$$Dp^x = BASEDp^x + REMAINDp^x + PSp^x$$

and:

$$NCSMp^x = CRR^x + ISM^x + NTSM^x$$

and:

$$RFpd = Rpd/P:Sales$$

and:

$$WCFpd = \frac{[(WCApd \times CC) - (WCApd \times CD)] + (WCApd \times CD) + WCRpd}{(1 - TR)} \Big/ P : Sales$$

and:

$$WCApd = Dp \times (DL/365)$$

Where:

BASEDp	Peak period base use demand charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August's daily loads.
CC	Weighted cost of capital as defined in Section 500.
CD	Weighted cost of debt as defined in Section 5.00.
CRR	The returnable Capacity Release Revenues allocated to the peak period. See Section 7.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dp	Demand Charges allocated to the peak period as defined in Section

COST OF GAS ADJUSTMENT CLAUSE

5.00.

NCSMp^{x} The sum of the returnable Interruptible Non-Core Sales Margins, the returnable Capacity Release Revenues and the Off-System margins.

ISM The returnable Interruptible Sales Margins allocated to the peak period. See Section 7.00.

NTSM The returnable Off-System Sales Margins allocated to the peak period. See Section 7.00.

P:Sales Forecasted sales volumes associated with the peak period.

REMAINDp Peak period remaining use demand charges assigned to classes on the basis of their load's contribution to the design day load less their base use entitlements to pipeline supplies. This remaining capacity cost is allocated to seasons using the Proportional Responsibility (PR) allocator.

RFpd Peak demand charge reconciliation adjustment factor per billed peak sales volume associated with demand charges related to the peak period.

Rpd Reconciliation Costs - Peak demand deferred gas costs, Account 175.21 balance, inclusive of the associated Account 175.21 interest, as outlined in Section 9.00.

TR Combined Tax Rate as defined in Section 5.00

WCApd Demand charges allowable for working capital application as defined in Section 10.00.

WCFpd Working Capital allowable factor per billed peak sales volume associated with demand charges allocated to the peak period as defined in Section 10.00.

WCRpd Working Capital reconciliation adjustment associated with peak demand charges - Account 176.24 balance as outlined in Section 10.00.

x Designates Load Factor Specific allocation of costs, based on Simplified Market Based Allocation factors as determined in the Company's most recent rate proceeding.

PSpx Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Peak Commodity Factor (CFp) Formula

$$CFp^{x} = \left[\frac{Cp^{x} - NCCCp^{x} + FC^{x}}{P : Sales^{x}} \right] + RFpc + WCFpc$$

and:

$$Cp^{x} = BASECp^{x} + REMAINCpx$$

and:

$$RFpc = Rpc / P:Sales$$

and:

COST OF GAS ADJUSTMENT CLAUSE

$$WCFpc = \frac{[(WCApc \times CC) - (WCApc \times CD)] + (WCApc \times CD) + WCRpc}{(1 - TR)} \Big/ P: Sales$$

and:

$$WCApc = Cp \times (DL/365)$$

Where:

BASECp	Peak period base use commodity charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August daily loads.
CC	Weighted costs of capital as defined in Section 5.00
CD	Weighted costs of debt as defined in Section 5.00.
Cp	Commodity Charges allocated to the peak period as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
FC	Inventory finance charges as defined in Section 5.00.
NCCCp	Non-Core Commodity Costs allocated to the peak period as defined in Section 5.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINCp	Peak period remaining use commodity charges computed as dispatched commodity costs less base use commodity costs.
RFpc	Peak commodity charge reconciliation adjustment factor per billed peak sales volume associated with commodity charges related to the peak period.
Rpc	Reconciliation Adjustment Costs - Account 175.23 balance, inclusive of the associated Account 175.23 interest, as outlined in Section 9.00.
TR	Combined Tax rate as defined in Section 5.00.
WCApc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFpc	Working Capital allowable factor per peak sales volume associated with commodity charges allocated to the peak period as defined in Section 10.00.
WCRpc	Working Capital reconciliation adjustment associated with peak commodity charges Account 175.24 balance as outlined in Section 10.00.
x	Designates Load Factor class specific allocation of costs, based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.

Off-Peak GAF Formula

COST OF GAS ADJUSTMENT CLAUSE

The Off-Peak GAF shall be comprised of an off-peak demand factor (Dfop) an off-peak production and storage demand factor (PSop), an off-peak commodity factor (Cfop), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF), defined in Section 16.00 for the Company's High and Low Load Factor classes, and calculated at the beginning of the off-peak season according to the following formula.

$$GAFop^X = DFop^X + CFop^X + PSopx + BDF - R1 - R2$$

Off-Peak Demand Factor (DFop) Formula

$$DFop^x = \frac{Dop^x}{OP:Sales^x} + RFopd + WCFopd$$

and:

$$Dop^X = Sum:BLDop^X + (Sum:BLDXop^X \times (1 - PR))$$

and:

$$RFopd = Ropd / OP:Sales$$

and:

$$WCFopd = \frac{[(WCAopd \times CC) - (WCAopd \times CD)]}{(1 - TR)} \cdot \frac{}{(OP:Sales)} + (WCAopd \times CD) + WCRopd$$

and:

$$WCAopd = Dop\ (DL/365)$$

Where:

BLDop Demand charges billed to the Company during the off peak period for the portion of base demand associated with serving base load requirements as defined in Section 5.00.

BLDXop Base demand costs in excess of demand costs associated with base load level billed to the Company during the off-peak period.

CC Weighted cost of capital as defined in Section 5.00.

COST OF GAS ADJUSTMENT CLAUSE

CD	Weighted cost of debt as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dop	Demand charges allocated to the off-peak period as defined in Section 5.00.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
PR	Proportional Responsibility Allocator - A percentage representing a portion of capacity/product charges incurred in the off-peak season and assigned to the peak period calculated in each CGA filing as defined in Section 5.0.
RFopd	Off-peak demand charge reconciliation adjustment factor per billed off peak throughput volume associated with demand charges related to the off peak period.
Ropd	Reconciliation Costs - Account 175.11 balance, inclusive of the associated Account 175.11 interest, as outlined in Section 9.00.
SMBA	Simplified Market Based Allocator – Load Factor specific allocator as defined in Section 5.00
TR	Combined Tax rate as defined in Section 5.0
WCAopd	Demand charges allowable for working capital application as defined in Section 6.1.
WCFopd	Working Capital factor allowable per billed off-peak sales associated with demand charges allocated to the off-peak period as defined in Section 10.0
WCRopd	Working Capital reconciliation adjustment associated with off-peak demand charges balance account 175.14 balance as outlined in Section 10.0.
x	Designates Load Factor specific allocation of costs based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.
PS_{op}^{x}	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to off-peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Off-Peak Commodity Factor (CFop) Formula

$$CFop^{x} = \frac{Cop^{x} - NCCCop^{x}}{OP : Sales^{x}} + RFopc + WCFopc$$

and:

$$Cop^{X} = Sum{:}OPC^{X} - BOao^{X} - INJop^{X} - LIQop^{X}$$

COST OF GAS ADJUSTMENT CLAUSE

and:

$BOao^X = [(BOop - (BOvolop \times (TPop/TPvolop))) MBA^X]$

and:

RFopc = Ropc/OP:Sales

and:

$$WCFopc = \frac{[(WCAopc \times CC)-(WCAopc \times CD)]}{(1 - TR)} + (WCAopc \times CD) + WCRopc$$
$$OP : Sales$$

and:

WCAopc = Cop (DL/365)

Where:

BOao	LNG Boil-off allocation as defined in Section 9.00.
BOop	Cost of LNG Boil-off during the off-peak period.
BOvolop	LNG Boil-off volumes purchased in the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
Cop	Commodity Charges billed to the off-peak period as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers. See Section 10.00.
INJop	Injections into underground storage during the off-peak period.
LIQop	Liquefactions into storage during the off-peak period.
NCCCop	Non-core commodity costs allocated to the off-peak period as defined in Section 6.05.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
OPC	Commodity charges associated with gas supply sent out in the off-peak season as defined in Section 5.00.
RFopc	Off peak commodity charge reconciliation adjustment factor per billed off peak sales volume associated with commodity charges related to the off-peak period.
Ropc	Reconciliation Adjustment Cost - Account 175.13 balance, inclusive of the associated Account 175.13 interest, as outlined in Section 9.00.
TPop	Total pipeline commodity purchase charges for the off-peak period.

COST OF GAS ADJUSTMENT CLAUSE

TPvolop	Total pipeline purchase volumes for the off-peak period.
TR	Combined Tax rate as defined in Section 5.00.
WCAopc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFopc	Working Capital allowable per off-peak sales volume associated with commodity charges allocated to the off-peak period as defined in Section 10.00.
WCRopc	Working Capital reconciliation adjustment associated with off-peak commodity charges - Account 176.14 balance, as outlined in Section 10.00.
x	Designates Load Factor specific allocation of costs, based on Simplified Market Based Allocation factors.

7.0 Interruptible Sales, Off-System Sales and Capacity Release Revenues

A threshold level of margins will be established annually and separately for Interruptible Sales, Off-System Sales and Capacity Release Revenues. Any margins earned in excess of the predetermined level shall be divided between the Company and its firm sales customers under a 25/75 sharing arrangement. The threshold level of margins shall be adjusted to reflect additions or losses from Customers who switch from FT, FS or Interruptible Transportation ("IT") to IS and conversely, from IS to FT, FS or IT. The Company shall adjust the threshold level annually to reflect Interruptible Sales, Off-System sales, and capacity release revenues for the twelve-month period ending April 30 of each year.

Margins from Interruptible Sales, Off-System Sales and Capacity Release will be reflected as separate credits in the peak season GAF and shall be calculated as the sum of the following:

(1) 100% of the margins earned up to the predetermined threshold level.
(2) 75% of the margins earned in excess of the predetermined threshold level.

8.0 Gas Suppliers' Refunds - Accounts 265.85 and 265.86

Refunds from upstream capacity suppliers and suppliers of gas are credited to Account 265.85, "Refund-November" if received during the months of March through August, and to Account 265.86 "Refund-May", if received during the months of September through February.

A refund program shall be initiated with each semiannual GAF filing and shall remain in effect for a period of one year. The balance in Account 265.85 shall be placed into a refund program with each November filing. The balance in Account 265.86 shall be placed into a refund program with each May filing. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous

COST OF GAS ADJUSTMENT CLAUSE

program was initiated. The Company shall track and report on all Account 265.85 and Account 265.86 activities. If during any twelve-month period commencing with the billing month of November for Account 265.85 and May for Account 265.86, the projected supplier refund factor is less than one-hundredth of a cent per therm ($0.0001), the respective supplier refund account balance shall be transferred into Account 175.26 or Account 175.16 for the November and May filings respectively.

Gas Supplier's Refund Factors

R1 The per unit supplier refund associated with the Refund – May program. The following formula shall be used to calculate the R1 factor.

$$R1 = \frac{R1\$ + I}{A:Sales}$$

Where:

R1$	Ending balance in Account 265.86 "Refund – May"
I	Total forecasted interest calculated on the R1$ balance computed at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

R2 The per unit supplier refund associated with the Refund – November program. The following formula shall be used to calculate the R2 factor.

$$R2 = \frac{R2\$ + I}{A:Sales}$$

Where:

R2$	Ending balance in Account 265.85 "Refund – November"
I	Total forecasted interest calculated on the R2$ balance computed at the Federal Reserve Prime Rate based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

9.0 Reconciliation Adjustments – Other than Working Capital

COST OF GAS ADJUSTMENT CLAUSE

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Capacity Costs Allowable per Peak Demand Formula shall be:

i. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the peak season.

ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.

iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Charges associated with peaking, production and storage capacity to serve firm load in the peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service.

v. Credits associated with Non-Core Sales Margins or economic benefits from capacity release, off-system sales for resale and interruptible sales margins allocated to the firm sales service.

vi. Credits associated with daily imbalance charges billed transportation customers in the peak period.

vii. Peak demand Carrying Charges as defined in Section 5.00.

(b) Gas Costs Allowable Per Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefaction into storage.

ii. Credit non-core commodity costs assigned to non-core customers to which the CGAC does not apply, as defined in Section 6.06 (NCCCp).

iii. Inventory finance charges (FC).

iv. Peak commodity Carrying Charges as defined in Section 5.00.

(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity and product demand procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with transmission capacity and product demand procured by the Company to serve firm load in excess of base load requirements in the off-peak period

COST OF GAS ADJUSTMENT CLAUSE

iii. Credits associated with daily imbalance charges billed transportation customers in the off peak period.
iv. Off-peak demand Carrying Charges as defined in Section 5.00.
v. Other A & G and Acct. 851 charges associated with peaking production and storage capacity to serve firm load in the off-peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service

(d) Gas Costs Allowable Per Off-Peak Commodity Formula shall be:
i. Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.
ii. Credits associated with Non-core commodity costs from non-core sales to which the GAF is not applied, as defined in Section 5.00.
iii. Off-peak commodity Carrying Charges as defined in Section 5.00.

(2) Calculation of the Reconciliation Adjustments

Account 175 contains the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Peak Demand (Account 175.21), Peak Production and Storage Demand (175.22) ,Peak Commodity (Account 175.23), Off-Peak Demand (Account 175.11), Off-Peak Production and Storage Demand (175.12) and Off-Peak Commodity (Account 175.13). Account 175.21 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Peak Demand Factor for the High and Low Load Factor classes, (DFp^X) times monthly firm sales volumes forHigh and Low Load Factor classes, and the total capacity costs allowable per the peak demand formula. Account 175.22 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Peak Commodity Factor for the High and Low Load Factorclasses, (CFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total commodity costs allowable per the peak commodity formula. Account 175.22 shall contain the accumulated difference between revenues as calculated by multiplying the Peak Production and Storage Demand Factor for the High and Low Load Factor class, (PS_p^x) times monthly firm sales volumes forthe High and Low Load Factor classes, and the total production and storage costs allowable per the peak production and storage demand formula. Account 175.11 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Off-Peak Demand Factor for the High and Low Load Factor classes, ($DFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total

COST OF GAS ADJUSTMENT CLAUSE

capacity costs allowable per the off-peak demand formula. Account 175.13 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Off-Peak Commodity Factor for the High and Low Load Factor classes, ($CFop^{X}$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total commodity costs allowable per the off-peak commodity formula. Account 175.12 shall contain the accumulated difference between revenues as calculated by multiplying the Off-Peak Production and Storage Demand Factor for the High and Low Load Factor classes, (PS_{op}^{x}) times monthly firm sales volumes for the High and Low Load Factorclasses, and the total production and storage costs allowable per the off-peak production and storage demand formula.

Carrying Charges as defined in Section 5.00 shall be added to each end-of-the-month balance. The peak demand reconciliation adjustment factor (RFpd) shall be determined for use in the peak GAF calculation by dividing the peak demand account (175.21) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak production & storage demand reconciliation adjustment factor (RFppsd) shall be determined for use in the peak GAF calculation by dividing the peak production and storage demand account (175.22) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak commodity reconciliation adjustment factor (RFpc) shall be determined for use in the peak GAF calculation by dividing the peak commodity account (175.23) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The off-peak demand reconciliation adjustment factor (RFopd) shall be determined for use in the off peak GAF calculation by dividing the off-peak demand account (175.11) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak production and storage demand reconciliation adjustment factor (RFoppsd) shall be determined for use in the off-peak GAF calculation by dividing the off-peak production and storage demand account (175.12) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak commodity reconciliation adjustment factor (RFopc) shall be determined for use in the off-peak GAF calculation by dividing the off-peak commodity account (175.13) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period.

The peak period reconciliation will be filed thirty (30) days prior to the peak period GAF filing, which is seventy-five (75) days prior to the effective date.

The off-peak period reconciliation shall be filed thirty (30) days prior to the off-peak period GAF filing, which is seventy-five (75) days prior to the effective date.

COST OF GAS ADJUSTMENT CLAUSE

10.0 Working Capital Reconciliation Adjustments

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Working Capital Gas Costs Allowable Per Peak Demand Formula shall be:

i. Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the peak season.

ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.

iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Carrying Charges

(b) Working Capital Gas Costs Allowable Per Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average costs of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-Core Commodity Costs associated with non-core sales to which the GAF is not applied.

iii. Carrying charges.

(c) Working Capital Gas Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the off-peak period.

iii. Carrying charges.

(d) Working Capital Gas Costs Allowable Per Off-Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, procured by the company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.

COST OF GAS ADJUSTMENT CLAUSE

ii. Non-core commodity costs associated with non-core sales to which the GAF is not applied, as defined in section 6.05.
iii. Carrying charges.

(2) The peak and off-peak, demand, and commodity working capital requirements shall be calculated by applying the Company's days lag divided by 365 days to the working capital costs allowable per each formula.

(3) The peak and off-peak, demand, and commodity working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working capital requirement to calculate the respective returns on working capital. The interest portion of each working capital allowance is calculated by multiplying each working capital requirement by the weighted cost of debt. This portion is tax deductible. The return on each working capital less the interest portion of each working capital is then divided by one minus the tax rate. This figure plus the interest calculated above equals the working capital allowance for each.

(4) Calculation of the Reconciliation Adjustments

Accounts 175.14, 175.13, 175.24, and 175.23 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company plus Carrying Charges as defined in Section 5.00.

The components of the Company's purchased gas days lag shall be recalculated each season based upon actual CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenues. Each Account 175 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

The peak demand working capital reconciliation adjustment shall be determined for use in the peak demand factor calculations incorporating the peak demand working capital account 175.14 balance as of the peak reconciliation date designated by the Company. A peak commodity working capital reconciliation adjustment shall be determined for use in the peak commodity factor calculations incorporating the peak commodity working capital account 175.13 balance as of the peak reconciliation date designated by the Company. An off-peak working capital reconciliation adjustment (WCRopd) shall be determined for use in the off -peak demand factor calculations incorporating the off-peak demand working

COST OF GAS ADJUSTMENT CLAUSE

capital account (175.24) balance as of the off-peak reconciliation date designated by the Company. An off-peak commodity working capital reconciliation adjustment (WCRopc) shall be determined for use in the off-peak commodity working capital account (175.23) balance as of the off-peak reconciliation date designated by the Company.

11.0 Application of GAF to Bills

The Company will employ the GAFs as follows: The peak season rates to each Load Factor class shall be calculated by adding the respective peak demand factor and the peak commodity factor. The off-peak season rates to each Load Factor class shall be calculated by adding the respective off-peak demand factor and the off-peak commodity factor. The GAFs ($/therm) for each Load Factor class for each season shall be calculated to the nearest one-hundredth of a cent per therm ($0.0001) and will be applied to each customer's monthly sales volume within the corresponding Load Factor class.

12.0 Information Required to be Filed with the Department

Information pertaining to the cost of gas adjustment shall be filed with the Department in accordance with the Company's standardized forms approved by the Department. Required filings include a semiannual GAF filing which shall be submitted to the Department at least 45 days before the date on which a new GAF is to be effective.

Additionally the Company shall file with the Department a complete list of all gas costs claimed as recoverable through the CGAC over the previous season, as included in the seasonal reconciliation. This information shall be submitted with each seasonal GAF filing, along with complete documentation of the reconciliation adjustment calculations.

13.0 Other Rules

(1) The Department may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.
(2) The Company may, at any time, file with the Department an amended GAF. An amended GAF filing must be submitted 10 days before the first billing cycle of the month in which it is proposed to take effect.
(3) The Department may, at any time, require the Company to file an amended GAF.

COST OF GAS ADJUSTMENT CLAUSE

(4) The operation of the cost of gas adjustment clause is subject to all powers of suspension and investigation vested in the Department by G.L. c.164.

14.0 Customer Notification

The Company will design a notice, which explains in simple terms to customers the GAF, the nature of any change in the GAF and the manner in which the GAF is applied to the bill. The Company will submit this notice for approval at the time of each GAF filing.

Upon approval by the Department, the Company must immediately distribute these notices to all of its customers either through direct mail or with its bills.

15.0 Bad Debt Allowance

15.01 Purpose

The purpose of this provision is to establish a procedure that, subject to the jurisdiction of the Department, allows Bay State to adjust, on a semi-annual basis, its rates for the recovery of Bad Debt Expense

15.02 Bad Debt (BDF) Formula

The Bad Debt (BDF) Formula shall be computed on an annual basis using forecasts of bad debt expense associated with gas costs, gas costs, carrying charges, sales volumes, and a working capital allowance. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing. The forecast of bad debt expense associated with gas costs shall be based on the Company's projected gas costs in the respective seasonal GAF filings and the percent of net write-offs to total firm revenues as determined in the Company's last rate proceeding.

The calculation at the beginning of the off-peak season shall be on a projected annual basis. The calculation at the beginning of the peak season will update the remaining months of the projected annual period with actual bad debt expenses and collections for the available months and projections for the remaining months of the annual period. The following formula shall be used to calculate the Bad Debt factor.

$$BDF = \frac{BD + RAbd + WCbd + I}{A:Sales}$$

COST OF GAS ADJUSTMENT CLAUSE

and:

$$WCbd = \frac{(WCAbd * CC) - (WCAbd * CD)}{(1 - TR)} + (WCAbd * CD)$$

and:

$$WCAbd = BD * (DL/365)$$

Where:

A:Sales Forecast annual sales volumes.

BD Forecast Bad Debt Expense as defined in Section 5.00; derived by multiplying the forecast annual gas costs by the percent of annual net write-offs to annual firm revenues as determined in D.T.E. 05-27.

CC Weighted cost of capital as defined in Section 5.00.

CD Weighted cost of debt as defined in Section 5.00.

DL Number of days lag from the purchase of gas from suppliers to the payment by customers.

I Interest on total bad debt allowance plus working capital on bad debt calculated at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.

RAbd Bad Debt Expense reconciliation adjustment - Account 175.31 balance.

TR Combined Tax rate as defined in Section 5.00.

WCAbd Bad Debt allowable for working capital application defined as the costs associated with the gas cost portion of bad debt incurred by the Company to serve firm load.

WCbd Working Capital Allowance associated with the gas portion of bad debt for the period including the Pretax Weighted Cost of Capital as defined in Section 5.00.

15.03 Bad Debt Reconciliation Adjustment

Account 175.31 shall contain the accumulated difference between the annual revenues toward bad debt, as calculated by multiplying the bad debt factors (BDF) times monthly firm sales volumes, and the annual allowed Bad Debt expenses, allowed working capital on Bad Debt and Carrying Charges as defined in Section 5.00.

An annual bad debt reconciliation adjustment (RAbd - as defined in Section 15.02) shall

COST OF GAS ADJUSTMENT CLAUSE

be determined for use in the bad debt factor calculations incorporating the bad debt working capital account (175.32) balance as of the reconciliation date designated by the Company.

(a) Costs Allowable per Bad Debt Formula shall be:

i. Un-collectable gas costs incurred by the Company to serve firm sales load, as determined by deriving the portion of actual net write-offs associated with gas cost collections.

ii. Account 175.32 – Bad Debt, Carrying Charges.

iii. Working Capital Gas Costs Allowable per Bad Debt Formula, which shall be charges associated with bad debt incurred by the Company to serve firm sales load and applied to the working capital formula.

BAY STATE GAS COMPANY

M.D.T.E. No. 36
Cancels M.D.T.E. No. 3
Page 1 of 212~~121~~

COST OF GAS ADJUSTMENT CLAUSE

Section

1.0 Purpose

The purpose of this clause is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company"), subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on a semiannual basis, its rates for firm gas sales service in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchase gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit all supplier refunds and the margins above the Annual Threshold associated with capacity credits from non-core sales and transportation, interruptible sales and transportation and capacity release sales to firm ratepayers.

2.0 Applicability

This Cost of Gas Adjustment ("CGAC") shall be applicable to Bay State and all firm gas sales made by Bay State, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the Department. See Section 13.0, "Other Rules."

COST OF GAS ADJUSTMENT CLAUSE

3.0 Cost of Firm Gas Allowable for CGAC

All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the CGAC. Any costs recovered through application of the CGAC shall be identified and explained fully in the semi-annual filings outlined in Section 12.0.

4.0 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

5.0 Definitions

The following terms shall be defined in this section, unless the context requires otherwise.

(1) **Annual Threshhold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.

(2) **Bad Debt Expense** - is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.

(3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.

(4) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.

(5) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal*.

(6) **Economic Benefit** - The difference between the revenues received and the marginal cost determined to serve non-core customers.

(7) **Interruptible Sales Margins** - The economic benefit derived from the interruptible sale of gas downstream of the Company's distribution system.

COST OF GAS ADJUSTMENT CLAUSE

(8) **Inventory Finance Charges** - As incurred or billed each month for the carrying costs on the value of the balance of inventory gas for the respective month. The total charges shall represent an accumulation of the projected monthly charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate of the Company or through a trust or other financing vehicle.

(9) **Local Production Capacity and Storage Costs** - Include the ancillary supply costs of providing local manufactured gas, gas dispatching, gas acquisition, and miscellaneous A&G costs as determined in the Company's most recent rate proceeding. Per this proceeding, $7,401,961 shall be allocated to the peak period and $325,300 shall be allocated to the off-peak period.

(10) **SMBA** – Simplified Market Based Allocation Method - Used in determining the allocation of gas costs among High and Low Load Factor classes.

(11) **Non-Core Commodity Costs** - The commodity cost of gas assigned to non-core sales to which the GAF is not applied. Non-core sales include sales made under interruptible contracts, non-core contracts and off-system sales.

(12) **Non-Core Sales Margins** - The economic benefit derived from non-core transactions to which the GAF is not applied, including interruptible sales and other non-core sales generated from the use of the Company's Gas Supply resource portfolio.

(13) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

(14) **Number of Days Lag** - The number of days lag to calculate the purchased gas working capital requirement as approved by the Department.

(15) **Off-Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the off-peak season.

(16) **Off-Peak Demand** - Unless otherwise approved by the Department, the gas supply demand and transmission capacity assigned by the Company to serve firm load in the off-peak season.

(17) **Off-Peak Period** - May through October.

(18) **Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the peak season.

(19) **Peak Demand** - Unless otherwise approved by the Department, gas supply demand, peaking demands, storage and transmission capacity assigned by the Company to service firm load in the peak season.

(20) **Peak Period** - November through April.

(21) **PR Allocator** - The percentage allocated for the portion of annual capacity charges assigned to the seasons calculated in each CGA filing.

(22) **Pretax Weighted Cost of Capital** - The result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one, minus the currently effective combined tax rate, plus the weighted cost of debt.

COST OF GAS ADJUSTMENT CLAUSE

(23) **Purchased Gas Working Capital** - The allowable working capital derived from peak and off-peak, demand and commodity related costs.

(24) **Tax Rate** is the combined State and Federal income tax rate.

(25) **Weighted Cost of Capital** is the weighted cost of capital as set in the Company's most recent base rate case.

(26) **Weighted Cost of Debt** is the weighted cost of debt as set in the Company's most recent base rate case.

6.0 Gas Adjustment Factor (GAF) Formula

The Gas Adjustment Factor (GAF) Formula shall be computed on a semiannual basis using forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

A separate seasonal GAF will be computed for the combined Low Load Factor classes namely Rates R-3, R-4, G-40, G-41, G-42 and G-43; and for the combined High Load Factor classes namely Rates R-1, R-2, OL, G-50, G-51, G-52 and G-53. The calculation of each seasonal GAF utilizes information periodically established by the DTE. The table below lists the following approved cost factors as approved in D.T.E. 05-27:

Local Production & Storage Cost	$7,727,261
LNG/LPG Production Cost included above	$5,258,855
Bad Debt Expense Percentage	2.17~~84~~%

Peak GAF Formula

The Peak GAF shall be comprised of a peak demand factor (DFp), a peak commodity factor (CFp), a peak production and storage demand factor (PSp), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF~~p~~) defined in Section 15.00, for the Company's High and Low Load Factor classes and calculated at the beginning of the peak season according to the following formula:

$$GAFp^x = DFp^x + PSpx^{PSp*} + CFp^x + BDF - R1 - R2$$

COST OF GAS ADJUSTMENT CLAUSE

Peak Demand Factor (DFp) Formula

$$DFp^x = \frac{Dp^x - NCSMp^x - \sout{STRANDp^x}}{P : Sales^x} + RFpd + WCFpd$$

and:

$$Dp^x = BASEDp^x + REMAINDp^x + PSp^x - \sout{SBDp^x}$$

and:

$$NCSMp^x = CRR^x + ISM^x + NTSM^x$$

and:

$$RFpd = Rpd/P:Sales$$

and:

$$WCFpd = \frac{[(WCApd \times CC) - (WCApd \times CD)]+(WCApd \times CD)+ WCRpd}{(1 - TR)} \cdot \frac{1}{P : Sales}$$

and:

$$WCApd = Dp \times (DL/365)$$

Where:

BASEDp	Peak period base use demand charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August's daily loads.
CC	Weighted cost of capital as defined in Section 500.
CD	Weighted cost of debt as defined in Section 5.00.
CRR	The returnable Capacity Release Revenues allocated to the peak period. See Section 7.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dp	Demand Charges allocated to the peak period as defined in Section

COST OF GAS ADJUSTMENT CLAUSE

5.00.

$NCSMp^x$	The sum of the returnable Interruptible Non-Core Sales Margins, the returnable Capacity Release Revenues and the Off-System margins.
ISM	The returnable Interruptible Sales Margins allocated to the peak period. See Section 7.00.
NTSM	The returnable Off-System Sales Margins allocated to the peak period. See Section 7.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINDp	Peak period remaining use demand charges assigned to classes on the basis of their load's contribution to the design day load less their base use entitlements to pipeline supplies. This remaining capacity cost is allocated to seasons using the Proportional Responsibility (PR) allocator.
RFpd	Peak demand charge reconciliation adjustment factor per billed peak sales volume associated with demand charges related to the peak period.
Rpd	Reconciliation Costs - Peak demand deferred gas costs, Account 175.21 balance, inclusive of the associated Account 175.21 interest, as outlined in Section 9.00.
~~STRANDp~~	~~Stranded production and Storage costs assigned to the peak period and classes in the same manner as remaining use demand charges.~~
TR	Combined Tax Rate as defined in Section 5.00
WCApd	Demand charges allowable for working capital application as defined in Section 10.00.
WCFpd	Working Capital allowable factor per billed peak sales volume associated with demand charges allocated to the peak period as defined in Section 10.00.
WCRpd	Working Capital reconciliation adjustment associated with peak demand charges - Account 176.24 balance as outlined in Section 10.00.
x	Designates Load Factor Specific allocation of costs, based on Simplified Market Based Allocation factors as determined in the Company's most recent rate proceeding.
PSpx	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Peak Commodity Factor (CFp) Formula

$$CFp^x = \left[\frac{Cp^x - NCCCp^x + FC^x}{P : Sales^x} \right] + RFpc + WCFpc$$

and:

$$Cp^x = BASECp^x + REMAINCpx - \sim\!\!SBCp\!\!\sim^x$$

and:

$$RFpc = Rpc / P:Sales$$

COST OF GAS ADJUSTMENT CLAUSE

and:

$$WCFpc = \frac{[(WCApc \times CC) - (WCApc \times CD)] + (WCApc \times CD) + WCRpc}{(1 - TR)} \div P: Sales$$

and:

$$WCApc = Cp \times (DL/365)$$

Where:

BASECp	Peak period base use commodity charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August daily loads.
CC	Weighted costs of capital as defined in Section 5.00
CD	Weighted costs of debt as defined in Section 5.00.
Cp	Commodity Charges allocated to the peak period as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
FC	Inventory finance charges as defined in Section 5.00.
NCCCp	Non-Core Commodity Costs allocated to the peak period as defined in Section 5.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINCp	Peak period remaining use commodity charges computed as dispatched commodity costs less base use commodity costs.
RFpc	Peak commodity charge reconciliation adjustment factor per billed peak sales volume associated with commodity charges related to the peak period.
Rpc	Reconciliation Adjustment Costs - Account 175.23 balance, inclusive of the associated Account 175.23 interest, as outlined in Section 9.00.
TR	Combined Tax rate as defined in Section 5.00.
WCApc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFpc	Working Capital allowable factor per peak sales volume associated with commodity charges allocated to the peak period as defined in Section 10.00.
WCRpc	Working Capital reconciliation adjustment associated with peak commodity charges Account 175.24 balance as outlined in Section 10.00.
x	Designates Load Factor class specific allocation of costs, based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.

COST OF GAS ADJUSTMENT CLAUSE

Off-Peak GAF Formula

The Off-Peak GAF shall be comprised of an off-peak demand factor (Dfop) an off-peak production and storage demand factor (PSop), an off-peak commodity factor (Cfop), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF), defined in Section 16.00 for the Company's High and Low Load Factor classes, and calculated at the beginning of the off-peak season according to the following formula.

$$GAFop^X = DFop^X + CFop^X + PSopx + BDF - R1 - and - R2$$

Off-Peak Demand Factor (DFop) Formula

$$DFop^X = \frac{Dop^X}{OP:Sales^X} + RFopd + WCFopd$$

and:

$$Dop^X = Sum:BLDop^X + (Sum:BLDXop^X \times (1 - PR))$$

and:

$$RFopd = Ropd / OP:Sales$$

and:

$$WCFopd = \frac{[(WCAopd \times CC) - (WCAopd \times CD)]}{(1 - TR)} \cdot \frac{}{(OP:Sales)} + (WCAopd \times CD) + WCRopd$$

and:

$$WCAopd = Dop\ (DL/365)$$

Where:

BLDop — Demand charges billed to the Company during the off peak period for the portion of base demand associated with serving base load requirements as defined in Section 5.00.

BLDXop — Base demand costs in excess of demand costs associated with base load level billed to the

COST OF GAS ADJUSTMENT CLAUSE

	Company during the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dop	Demand charges allocated to the off-peak period as defined in Section 5.00.
~~LBop~~	~~Portion of Upstream Pipeline Reservation Charges assigned to Load Balancing.~~
OP:Sales	Forecasted sales volumes associated with the off-peak period.
PR	Proportional Responsibility Allocator - A percentage representing a portion of capacity/product charges incurred in the off-peak season and assigned to the peak period calculated in each CGA filing as defined in Section 5.0.
RFopd	Off-peak demand charge reconciliation adjustment factor per billed off peak throughput volume associated with demand charges related to the off peak period.
Ropd	Reconciliation Costs - Account 175.11 balance, inclusive of the associated Account 175.11 interest, as outlined in Section 9.00.
SMBA	Simplified Market Based Allocator – Load Factor specific allocator as defined in Section 5.00
TR	Combined Tax rate as defined in Section 5.0
WCAopd	Demand charges allowable for working capital application as defined in Section 6.1.
WCFopd	Working Capital factor allowable per billed off-peak sales associated with demand charges allocated to the off-peak period as defined in Section 10.0
WCRopd	Working Capital reconciliation adjustment associated with off-peak demand charges balance account 175.14 balance as outlined in Section 10.0.
x	Designates Load Factor specific allocation of costs based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.
PS_{op}^{x}	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to off-peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Off-Peak Commodity Factor (CFop) Formula

$$CFop^{x} = \frac{Cop^{x} - NCCCop^{x}}{OP : Sales^{x}} + RFopc + WCFopc$$

COST OF GAS ADJUSTMENT CLAUSE

and:

$Cop^X = Sum:OPC^X - BOao^X - INJop^X - LIQop^X$

and:

$BOao^X = [(BOop - (BOvolop \times (TPop/TPvolop))) MBA^X]$

and:

RFopc = Ropc/OP:Sales

and:

$$WCFopc = \frac{\frac{[(WCAopc \times CC)-(WCAopc \times CD)]}{(1 - TR)} + (WCAopc \times CD) + WCRopc}{OP : Sales}$$

and:

WCAopc = Cop (DL/365)

Where:

BOao	LNG Boil-off allocation as defined in Section 9.00.
BOop	Cost of LNG Boil-off during the off-peak period.
BOvolop	LNG Boil-off volumes purchased in the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
Cop	Commodity Charges billed to the off-peak period as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers. See Section 10.00.
INJop	Injections into underground storage during the off-peak period.
LIQop	Liquefactions into storage during the off-peak period.
NCCCop	Non-core commodity costs allocated to the off-peak period as defined in Section 6.05.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
OPC	Commodity charges associated with gas supply sent out in the off-peak season as defined in Section 5.00.
RFopc	Off peak commodity charge reconciliation adjustment factor per billed off peak sales

COST OF GAS ADJUSTMENT CLAUSE

	volume associated with commodity charges related to the off-peak period.
Ropc	Reconciliation Adjustment Cost - Account 175.13 balance, inclusive of the associated Account 175.13 interest, as outlined in Section 9.00.
TPop	Total pipeline commodity purchase charges for the off-peak period.
TPvolop	Total pipeline purchase volumes for the off-peak period.
TR	Combined Tax rate as defined in Section 5.00.
WCAopc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFopc	Working Capital allowable per off-peak sales volume associated with commodity charges allocated to the off-peak period as defined in Section 10.00.
WCRopc	Working Capital reconciliation adjustment associated with off-peak commodity charges - Account 176.14 balance, as outlined in Section 10.00.
x	Designates Load Factor specific allocation of costs, based on Simplified Market Based Allocation factors.

7.0 Interruptible Sales, Off-System Sales and Capacity Release Revenues

A threshold level of margins will be established annually and separately for Interruptible Sales, Off-System Sales and Capacity Release Revenues. Any margins earned in excess of the predetermined level shall be divided between the Company and its firm sales customers under a 25/75 sharing arrangement. The threshold level of margins shall be adjusted to reflect additions or losses from Customers who switch from FT, FS or Interruptible Transportation ("IT") to IS and conversely, from IS to FT, FS or IT. The Company shall adjust the threshold level annually to reflect Interruptible Sales, Off-System sales, and capacity release revenues for the twelve-month period ending April 30 of each year.

Margins from Interruptible Sales, Off-System Sales and Capacity Release will be reflected as separate credits in the peak season GAF and shall be calculated as the sum of the following:

(1) 100% of the margins earned up to the predetermined threshold level.
(2) 75% of the margins earned in excess of the predetermined threshold level.

8.0 Gas Suppliers' Refunds - Accounts 265.85 and 265.86

Refunds from upstream capacity suppliers and suppliers of gas are credited to Account 265.85, "Refund-November" if received during the months of March through August, and to Account 265.86 "Refund-May", if received during the months of September through February.

A refund program shall be initiated with each semiannual GAF filing and shall remain in effect

COST OF GAS ADJUSTMENT CLAUSE

for a period of one year. The balance in Account 265.85 shall be placed into a refund program with each November filing. The balance in Account 265.86 shall be placed into a refund program with each May filing. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. The Company shall track and report on all Account 265.85 and Account 265.86 activities. If during any twelve-month period commencing with the billing month of November for Account 265.85 and May for Account 265.86, the projected supplier refund factor is less than one-hundredth of a cent per therm ($0.0001), the respective supplier refund account balance shall be transferred into Account 175.26 or Account 175.16 for the November and May filings respectively.

Gas Supplier's Refund Factors

R1 The per unit supplier refund associated with the Refund – May program. The following formula shall be used to calculate the R1 factor.

$$R1 = \frac{R1\$ + I}{A:Sales}$$

Where:

R1$	Ending balance in Account 265.86 "Refund – May"
I	Total forecasted interest calculated on the R1$ balance computed at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

R2 The per unit supplier refund associated with the Refund – November program. The following formula shall be used to calculate the R2 factor.

$$R2 = \frac{R2\$ + I}{A:Sales}$$

Where:

R2$	Ending balance in Account 265.85 "Refund – November"
I	Total forecasted interest calculated on the R2$ balance computed at the Federal Reserve Prime Rate based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

COST OF GAS ADJUSTMENT CLAUSE

9.0 Reconciliation Adjustments – Other than Working Capital

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Capacity Costs Allowable per Peak Demand Formula shall be:

i. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the peak season.

ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.

iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Charges associated with peaking, production and storage capacity to serve firm load in the peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service.

v. Credits associated with Non-Core Sales Margins or economic benefits from capacity release, off-system sales for resale and interruptible sales margins allocated to the firm sales service.

vi. Credits associated with daily imbalance charges billed transportation customers in the peak period.

vii. Peak demand Carrying Charges as defined in Section 5.00.

(b) Gas Costs Allowable Per Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefaction into storage.

ii. Credit non-core commodity costs assigned to non-core customers to which the CGAC does not apply, as defined in Section 6.06 (NCCCp).

iii. Inventory finance charges (FC).

iv. Peak commodity Carrying Charges as defined in Section 5.00.

(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity and product demand

COST OF GAS ADJUSTMENT CLAUSE

procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with transmission capacity and product demand procured by the Company to serve firm load in excess of base load requirements in the off-peak period

iii. Credits associated with daily imbalance charges billed transportation customers in the off peak period.

iv. Off-peak demand Carrying Charges as defined in Section 5.00.

v. Other A & G and Acct. 851 charges associated with peaking production and storage capacity to serve firm load in the off-peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service

(d) Gas Costs Allowable Per Off-Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Credits associated with Non-core commodity costs from non-core sales to which the GAF is not applied, as defined in Section 5.00.

iii. Off-peak commodity Carrying Charges as defined in Section 5.00.

(2) Calculation of the Reconciliation Adjustments

Account 175 contains the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Peak Demand (Account 175.21), Peak Production and Storage Demand (175.22) ,Peak Commodity (Account 175.23), Off-Peak Demand (Account 175.11), Off-Peak Production and Storage Demand (175.12) and Off-Peak Commodity (Account 175.13). Account 175.21 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Peak Demand Factor for the High and Low Load Factor classes, (DFp^X) times monthly firm sales volumes forHigh and Low Load Factor classes, and the total capacity costs allowable per the peak demand formula. Account 175.22 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Peak Commodity Factor for the High and Low Load Factorclasses, (CFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total commodity costs allowable per the peak commodity formula. Account 175.22 shall contain the accumulated difference between revenues as calculated by multiplying the Peak Production and Storage Demand Factor for the High and Low Load Factor class, (PS_p^x) times monthly firm sales volumes forthe High and Low Load Factor classes, and the

COST OF GAS ADJUSTMENT CLAUSE

total production and storage costs allowable per the peak production and storage demand formula. Account 175.11 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Off-Peak Demand Factor for the High and Low Load Factor classes, ($DFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total capacity costs allowable per the off-peak demand formula. Account 175.13 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Off-Peak Commodity Factor for the High and Low Load Factor classes, ($CFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total commodity costs allowable per the off-peak commodity formula. Account 175.12 shall contain the accumulated difference between revenues as calculated by multiplying the Off-Peak Production and Storage Demand Factor for the High and Low Load Factor classes, (PS_{op}^X) times monthly firm sales volumes for the High and Low Load Factorclasses, and the total production and storage costs allowable per the off-peak production and storage demand formula.

Carrying Charges as defined in Section 5.00 shall be added to each end-of-the-month balance. The peak demand reconciliation adjustment factor (RFpd) shall be determined for use in the peak GAF calculation by dividing the peak demand account (175.21) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak production & storage demand reconciliation adjustment factor (RFppsd) shall be determined for use in the peak GAF calculation by dividing the peak production and storage demand account (175.22) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak commodity reconciliation adjustment factor (RFpc) shall be determined for use in the peak GAF calculation by dividing the peak commodity account (175.23) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The off-peak demand reconciliation adjustment factor (RFopd) shall be determined for use in the off peak GAF calculation by dividing the off-peak demand account (175.11) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak production and storage demand reconciliation adjustment factor (RFoppsd) shall be determined for use in the off-peak GAF calculation by dividing the off-peak production and storage demand account (175.12) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak commodity reconciliation adjustment factor (RFopc) shall be determined for use in the off-peak GAF calculation by dividing the off-peak commodity account (175.13) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period.

The peak period reconciliation will be filed thirty (30) days prior to the peak period GAF filing, which is seventy-five (75) days prior to the effective date.

COST OF GAS ADJUSTMENT CLAUSE

The off-peak period reconciliation shall be filed thirty (30) days prior to the off-peak period GAF filing, which is seventy-five (75) days prior to the effective date.

10.0 Working Capital Reconciliation Adjustments

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Working Capital Gas Costs Allowable Per Peak Demand Formula shall be:

i. Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the peak season.

ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.

iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Carrying Charges

(b) Working Capital Gas Costs Allowable Per Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average costs of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-Core Commodity Costs associated with non-core sales to which the GAF is not applied.

iii. Carrying charges.

(c) Working Capital Gas Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the off-peak period.

iii. Carrying charges.

(d) Working Capital Gas Costs Allowable Per Off-Peak Commodity Formula shall be:

i. Charges associated with gas supplies, including any applicable taxes, procured by the company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in

COST OF GAS ADJUSTMENT CLAUSE

the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-core commodity costs associated with non-core sales to which the GAF is not applied, as defined in section 6.05.

iii. Carrying charges.

(2) The peak and off-peak, demand, and commodity working capital requirements shall be calculated by applying the Company's days lag divided by 365 days to the working capital costs allowable per each formula.

(3) The peak and off-peak, demand, and commodity working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working capital requirement to calculate the respective returns on working capital. The interest portion of each working capital allowance is calculated by multiplying each working capital requirement by the weighted cost of debt. This portion is tax deductible. The return on each working capital less the interest portion of each working capital is then divided by one minus the tax rate. This figure plus the interest calculated above equals the working capital allowance for each.

(4) Calculation of the Reconciliation Adjustments

Accounts 175.14, 175.13, 175.24, and 175.23 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company plus Carrying Charges as defined in Section 5.00.

The components of the Company's purchased gas days lag shall be recalculated each season based upon actual CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenues. Each Account 175 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

The peak demand working capital reconciliation adjustment shall be determined for use in the peak demand factor calculations incorporating the peak demand working capital account 175.14 balance as of the peak reconciliation date designated by the Company. A peak commodity working capital reconciliation adjustment shall be determined for use in the peak commodity factor calculations

COST OF GAS ADJUSTMENT CLAUSE

incorporating the peak commodity working capital account 175.13 balance as of the peak reconciliation date designated by the Company. An off-peak working capital reconciliation adjustment (WCRopd) shall be determined for use in the off -peak demand factor calculations incorporating the off-peak demand working capital account (175.24) balance as of the off-peak reconciliation date designated by the Company. An off-peak commodity working capital reconciliation adjustment (WCRopc) shall be determined for use in the off-peak commodity working capital account (175.23) balance as of the off-peak reconciliation date designated by the Company.

11.0 Application of GAF to Bills

The Company will employ the GAFs as follows: The peak season rates to each Load Factor class shall be calculated by adding the respective peak demand factor and the peak commodity factor. The off-peak season rates to each Load Factor class shall be calculated by adding the respective off-peak demand factor and the off-peak commodity factor. The GAFs ($/therm) for each Load Factor class for each season shall be calculated to the nearest one-hundredth of a cent per therm ($0.0001) and will be applied to each customer's monthly sales volume within the corresponding Load Factor class.

12.0 Information Required to be Filed with the Department

Information pertaining to the cost of gas adjustment shall be filed with the Department in accordance with the Company's standardized forms approved by the Department. Required filings include a semiannual GAF filing which shall be submitted to the Department at least 45 days before the date on which a new GAF is to be effective.

Additionally the Company shall file with the Department a complete list of all gas costs claimed as recoverable through the CGAC over the previous season, as included in the seasonal reconciliation. This information shall be submitted with each seasonal GAF filing, along with complete documentation of the reconciliation adjustment calculations.

13.0 Other Rules

(1) The Department may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

COST OF GAS ADJUSTMENT CLAUSE

(2) The Company may, at any time, file with the Department an amended GAF. An amended GAF filing must be submitted 10 days before the first billing cycle of the month in which it is proposed to take effect.
(3) The Department may, at any time, require the Company to file an amended GAF.
(4) The operation of the cost of gas adjustment clause is subject to all powers of suspension and investigation vested in the Department by G.L. c.164.

14.0 Customer Notification

The Company will design a notice, which explains in simple terms to customers the GAF, the nature of any change in the GAF and the manner in which the GAF is applied to the bill. The Company will submit this notice for approval at the time of each GAF filing.

Upon approval by the Department, the Company must immediately distribute these notices to all of its customers either through direct mail or with its bills.

15.0 Bad Debt Allowance

15.01 Purpose

The purpose of this provision is to establish a procedure that, subject to the jurisdiction of the Department, allows Bay State to adjust, on a semi-annual basis, its rates for the recovery of Bad Debt Expense

15.02 Bad Debt (BDF) Formula

The Bad Debt (BDF) Formula shall be computed on an annual basis using forecasts of bad debt expense associated with gas costs, gas costs, carrying charges, sales volumes, and a working capital allowance. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing. The forecast of bad debt expense associated with gas costs shall be based on the Company's projected gas costs in the respective seasonal GAF filings and the percent of net write-offs to total firm revenues as determined in the Company's last rate proceeding.

The calculation at the beginning of the off-peak season shall be on a projected annual basis. The calculation at the beginning of the peak season will update the remaining months of the projected annual period with actual bad debt expenses and collections for the available months and projections for the remaining months of the annual period. The following formula shall be used

COST OF GAS ADJUSTMENT CLAUSE

to calculate the Bad Debt factor.

$$BDF = \frac{BD + RAbd + WCbd + I}{A:Sales}$$

and:

$$WCbd = \frac{(WCAbd * CC) - (WCAbd * CD)}{(1 - TR)} + (WCAbd * CD)$$

and:

$$WCAbd = BD * (DL/365)$$

Where:

A:Sales Forecast annual sales volumes.

BD Forecast Bad Debt Expense as defined in Section 5.00; derived by multiplying the forecast annual gas costs by the percent of annual net write-offs to annual firm revenues as determined in D.T.E. 05-27~~the Company's last rate case~~.

CC Weighted cost of capital as defined in Section 5.00.

CD Weighted cost of debt as defined in Section 5.00.

DL Number of days lag from the purchase of gas from suppliers to the payment by customers.

I Interest on total bad debt allowance plus working capital on bad debt calculated at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.

RAbd Bad Debt Expense reconciliation adjustment - Account 175.31 balance.

TR Combined Tax rate as defined in Section 5.00.

WCAbd Bad Debt allowable for working capital application defined as the costs associated with the gas cost portion of bad debt incurred by the Company to serve firm load.

WCbd Working Capital Allowance associated with the gas portion of bad debt for the period including the Pretax Weighted Cost of Capital as defined in Section 5.00.

15.03 Bad Debt Reconciliation Adjustment

Account 175.31 shall contain the accumulated difference between the annual revenues toward bad debt, as calculated by multiplying the bad debt factors (BDF) times monthly

COST OF GAS ADJUSTMENT CLAUSE

firm sales volumes, and the annual allowed Bad Debt expenses, allowed working capital on Bad Debt and Carrying Charges as defined in Section 5.00.

An annual bad debt reconciliation adjustment (RAbd - as defined in Section 15.02) shall be determined for use in the bad debt factor calculations incorporating the bad debt working capital account (175.32) balance as of the reconciliation date designated by the Company.

(a) Costs Allowable per Bad Debt Formula shall be:

i. Un-collectable gas costs incurred by the Company to serve firm sales load, as determined by deriving the portion of actual net write-offs associated with gas cost collections.

ii. Account 175.32 – Bad Debt, Carrying Charges.

iii. Working Capital Gas Costs Allowable per Bad Debt Formula, which shall be charges associated with bad debt incurred by the Company to serve firm sales load and applied to the working capital formula.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 9, 2005

Responsible: Danny G. Cote, General Manager
Thomas E. McKain, Special Projects

RR-DTE-113: Provide an industry publication supporting comments regarding NIPSCO having had in place the most sophisticated and functionally rich customer information system in the industry prior to acquiring Bay State Gas.

Response: Attached RR-DTE-113 (A) is an article written by two NIPSCO executives. It highlights the functionality and flexibility of the NIPSCO CIS that was eventually modified to support the Bay State Requirements. Attachment RR-DTE-113 (B) is an article from the CIO of the American Gas Association. The key message from this article is that Northeast Utilities saw the strategic benefits of CIS when acquiring Yankee Gas. At the present time CIS is being or has been propagated to the other subsidiaries of Northeast Utilities.

Attachment RR-DTE-113 (A)

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CustomerService Implementation of a Successful CIS NIPSCO's emphasis on customer satisfaction led the utility to install a Customer Information System.

Mar 1, 1996 12:00 PM
By Charles W. Anderson, and John Dunn, Northern Indiana Public Service Co.

Do these phrases sound familiar? "Service is just a phone call away." "One stop stopping for all your needs." "We'll be there when you need us." These quotes are just a few of the promises found in the advertisements and brochures of many companies today. But what does it take behind the scenes to consistently fulfill this type of commitment to customers? One key ingredient is information. That's what led Northern Indiana Public Service Co. (NIPSCO), Hammond, Indiana, U.S., to launch a major project in partnership with IBM to design and install a new Customer Information System (CIS) serving more than one million accounts.

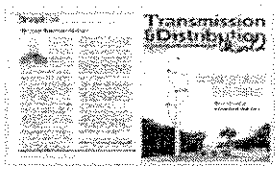
The Nov. 11, 1995 installation of NIPSCO's new CIS opened many opportunities for providing new and

Rick Bush
Editor
Bio | E-mail

expanded services to its customers. The client-server-based application was brought up to replace 10 separate systems that had been developed over the past 30 years. Starting with the analysis phase of the project and continuing through the course of the five-year effort,a strong team approach was used in the design, development, testing and training phases of the project, which involved more than 400 NIPSCO employees and several hundred technical developers and analysts. At each stage of the project, NIPSCO user input provided direction in launching the massive computer program.

NIPSCO Industries, Inc. is an energy-based holding company with both regulated and unregulated subsidiaries. Its major regulated subsidiaries include Northern Indiana Public Service Co., a utility comprised of two separate business sectors _ electric and gas _ plus two smaller natural-gas utilities: Kokomo Gas and Fuel Co. and Northern Indiana Fuel and Light Co., Inc., both in Indiana. Its unregulated subsidiaries include six separate businesses focusing on energy-related ventures primarily serving the Great Lakes and Midwest regions of the United States.

In evaluating the decision to replace its existing customer systems, NIPSCO carefully studied its customer-service management and technology strategies



in view of the overall business vision of the corporation. Extensive studies and customer-focus-group feedback clearly reflected that customer expectations must drive customer-service strategies to build customer satisfaction and grow market share. To build customer satisfaction, it is important to know and understand what your customers want from you. It's more than meeting their expectations _ it's anticipating, creating and exceeding their expectations.

Business Vision A utility's business vision must translate into specific strategies that will assure financial integrity and financial growth. NIPSCO's business vision seeks to "achieve superior earnings growth by being the premier supplier of energy products and services to the industrial heartland of America." This vision has enabled NIPSCO to look beyond its traditional markets, restructure its business and capitalize on its core competencies. As a part of this vision, the technology strategies must support the utility's goals of satisfying the customer and growing market share. One option is to enter into strategic partnerships with technology companies, as NIPSCO did with IBM to build its new CIS.

Customers want choice, speed, value and quality. They want fast, accurate and cost-effective service. To do this, we need extremely effective employees. NIPSCO

saw the need to mobilize its work force, understand employee needs and help them learn how to serve customers better. The utility found that this is best done through information sharing in a participative environment _ after all, employees are your company.

NIPSCO also realized that its business vision must drive the entire management strategy that addressed the many areas of today's environment: Customer focus - choice, speed, value and quality. Competition - for markets, products and services. Change - in employees' attitudes, competencies and responsibilities. Culture - company values, organizational structure and leadership style. Deregulation - its impact on customers' choices, which products and services are available, and where they are offered.

It's always difficult to move from "fighting fires" to building for the future. As NIPSCO looked at its business vision and the action plans required to make the vision a reality, it realized that its current technology needed a major overhaul to provide information and customer service. Information systems in place had been developed over 30 years, resulting in fragmented pieces of information that were difficult to retrieve. Maintenance and enhancements of existing systems were also becoming costly and sometimes impossible, resulting in "deadends" and the

inability to support the utility's expanding products and services.

Our business vision endorses the investment in technology that truly supports our strategies. The end result of that endorsement is a new Customer Information System (CIS) that integrates all customer service business functions (Table 1).

In order to satisfy the customer and attract new markets, the information, responsibility and authority need to be in the hands of the people closest to the customer. The new CIS serves as the catalyst in the following areas: Employees now know the relationships we have with our customers. Employees know the service commitments we have made with our customers. Our services must be delivered on time and at the least cost. We are able to sell to other companies the services that make up our core competencies.

Analysis and Design of CIS The initial phases of the CIS project at NIPSCO involved recruiting employees from various levels and classifications to provide the overall business requirements for the system. Nine joint application design (JAD) sessions brought together NIPSCO business experts, IBM technical analysts and design consultants to build the foundation for CIS. These brainstorming sessions established NIPSCO's business needs, outlined the technical

specifications of the system to support these requirements and provided a project roadmap. Throughout the course of the CIS project, NIPSCO followed a detailed implementation plan that tracked all major and minor project milestones by functional area and responsibility.

Given the size of the system, a segmented approach was used throughout the design phase. Business experts from NIPSCO, ranging from front-line customer service representatives, engineers, dispatchers, field service personnel, team leaders and various other support classifications were called upon to provide input during numerous design sessions. Technical design staff facilitated the sessions, documenting both business and system requirements for each functional area of CIS. During the course of each design session, the team created sample screen layouts for each CIS function and the navigation from one screen to another, providing the blueprint from which the system was built.

A prototype model of all major business functions was built upon completion of the design sessions to provide "hands on" interaction with CIS. A larger audience of subject matter experts was then asked to review the working prototype for completeness. This review provided a demonstration of how the system performed using scenarios of

business events that closely simulated real-life operations. For instance, in the service-order review session, an example of the CIS screens to create a "turn on" order was presented. In each design review session, feedback from participants was noted and changes to the system design were made when necessary to complete the design documentation.

The Usability Lab The next step allowed users to "test" how well CIS met their needs through participation in the Usability Lab. NIPSCO designed a usability lab patterned after IBM's Usability Lab in Atlanta, Georgia, U.S. The lab included an observation room, sophisticated videotaping equipment and a variety of communications tools. Employees with varying degrees of CIS knowledge were called upon to serve as evaluators, receiving basic CIS concepts as a group with some "hands on" use of the prototype. Evaluators then returned individually to the Usability Lab where common business scenarios were simulated in the form of "walk in" customers, phone calls or written instructions. The evaluators were asked to fulfill the requests using the CIS prototype. A mock "help desk" was available to assist with questions while the employee worked through each scenario independently, much the same as when performing day-to-day job duties. Each session was carefully documented, including

videotaping keystrokes, mouse movement, facial expressions and comments, to capture each step taken by evaluators during their sessions. After each Usability Lab session, documentation and feedback from the evaluators were used to recommend changes in the CIS design and, if necessary, further prototyping and testing through the usability lab process. Each business function was then approved by a business owner before the design specifications were released to the programming staff.

Putting CIS to the Test
As IBM completed the various pieces of the CIS program, a team composed of NIPSCO business experts and technical staff tested the functionality of the system using simulated common business events. Front line users, such as customer service representatives, engineers and dispatchers, were recruited as system testers to provide the business knowledge required to fully test CIS functions. Problems were documented, fixed and re-tested in a process that often repeated the testing cycle several times before all functions worked together properly. Automated testing that simulated large groups of employees performing a wide range of transactions was also conducted to confirm the operation of the system in a high volume environment.

As the testing progressed, another

dimension was added during weekend "stress tests," which opened the process to a larger audience of employees. The sessions allowed employees to test the system, completing scripts of common business transactions in a simulated "live" environment. The test yielded valuable feedback for the technical support staff and served as excellent reinforcement of NIPSCO's formal CIS training program.

Technical Architecture
The application programs executed at the workstation are written in C language. Functions performed at the workstation include extensive business logic, panel management, drag and drop actions, help displays, and numerous other capabilities. The application programs that provide host functionality are written in COBOL/2TM for a CICSTM and DB2R environment. In addition to traditional high-volume activity, such as billing, the host server _ an IBM ES9000R _ manages the CIS data repository. The IBM CIS technical architecture will also support a three-tier implementation if distributed data is required.

Communications
Internal communications regarding the CIS project status began in the early stages of system design and continued throughout the course of the project. CIS coordinators, representing each major department and

geographic location, facilitated communications and conducted eight pre-training sessions at each location to prepare employees for formal training classes. Communications were further enhanced through the use of a CIS overview video, CIS electronic bulletin board, monthly newsletter, a user telephone line, random employee contests based on CIS questions and other internal publications.

Overview of CIS Features Account Management maintains information describing service accounts and customer accounts. CIS also maintains relationships between service accounts, customer accounts and the customer. Orders that affect ownership and management of the accounts, such as "turn on" and "turn off" orders, are included. Field service manages the scheduling, assignment and execution of field service orders. This field work includes new business, utility service and meter orders, trouble orders, distribution service orders and investigation orders. The dispatch field service orders support the scheduling and execution of customer requests for service, including identification of available work dates for order scheduling, assignment of service personnel, dispatching of work and tracking the progress of each service order. NIPSCO employees schedule service orders using the CIS "Manpower Availability Calendar," which allows scheduling

within a 2-hr timespan.

New business provides an integrated CIS/work management system, storing and tracking each new business request as a "project" with one or more subordinate "cases."Workflow management routes, analyzes, and distributes work in the system to appropriate functions, individuals and processes. The major objective of the CIS work queues, or in-baskets, is to facilitate and expedite the flow of work and to reduce paper logging and tracking.

Work is broadly defined, encompassing orders, correspondence, information to be reviewed by team leaders, collection cases, billing exceptions and various other activities. CIS also uses an electronic supply cabinet for many of the forms used in NIPSCO's day-to-day operations, helping to reduce the paper and form requirements for many activities.

An extensive on-line help system is available within CIS for each function, screen and field. A special "How Do I" screen is provided for most common tasks, as well as easy access to NIPSCO's customer service policies and related procedures, which has replaced paper workbooks and manuals. A second level CIS support group at NIPSCO's Information Technology Help Center was established to respond to employee questions

regarding CIS and track the resolution of problems. Special software and telephone technology were installed to facilitate the help-desk operations.

Weekend CIS Installation Shortly after conversion and installation of CIS began, rolling snow clouds lined the skies, bringing in winds that kicked up what remained of the season's colored leaves. Within hours, a heavy coating of ice and snow had covered the northern quarter of the state, bringing down power lines and leaving some areas without electricity for hours at a time.

To avoid disrupting NIPSCO operations and customer service, the CIS team kept in contact with the utility's central dispatching department while maintaining the old customer order-entry system to help handle the thousands of customer trouble calls. A CIS "command center" tracked the hundreds of tasks taking place, making sure all was progressing on schedule despite weather complications. As the vicious storm slowly subsided, slight alterations were made to the CIS implementation schedule to keep things moving. Within minutes, all customer service representatives were making a smooth transition to a new technology and taking calls from customers using the new CIS.

Customer response to the new CIS has been

very positive. The ability to schedule service orders within a 2-hr timeframe is one of the most popular new features that provides what the service customer really needs and appreciates. The ability to update information immediately also generated many compliments from customers who now truly receive "one stop shopping" when they contact NIPSCO. TDW Charles W. Anderson received the bachelor of science, accounting and the master of business administration degrees from Indiana University. After serving in various management positions at NIPSCO, including manager of the Central Customer Service Center, Anderson was named project manager of the CIS Support Group.

John W. Dunn is group vice president and chief technology office, Corporate Services for NIPSCO. Since coming to NIPSCO in 1972, Dunn has held a number of executive positions from nuclear systems engineer to manager, plant engineering and construction; vice president, electric production and environmental affairs; senior vice president and general manager, energy distribution. He has the BSME from Marquette University, the MS nuclear engineering from the University of New Mexico and the MBA from Northwestern University. He is also a member of the American Gas Assoc., American Management Assoc., EEI and NSPE.

Back to Top

Attachment RR-DTE-113 (B)

Pipeline & Gas Journal
December issue 1999:

Money Well Spent

The Silver Lining in Y2K...Improved Infrastructure, Customer Care

by Gary Gardner, Chief Information Officer, American Gas Association, Washington, D.C.

By the time 1999 rolls into history and the Year 2000 begins, natural gas utilities will have spent more than an estimated $1 billion collectively to ensure that their computerized systems and functions perform reliably. This substantial dedication of resources may seem at first glance to have been "money for nothing," to paraphrase a best-selling rock song by Dire Straits.

But there is a silver lining in the Year 2000 issue for the local natural gas distribution companies that took the opportunity to enhance customer care, reliability or operating efficiency while addressing Y2K-related challenges.
Here are highlights of some of the Y2K-related benefits identified by several natural gas utilities.

Yankee Gas Services Co. launched in July 1999 a state-of-the-art customer information system designed to enhance customer service, improve efficiency and provide the tools needed for the company to grow in an increasingly competitive energy environment. The utility is Connecticut's largest natural gas distribution company, with about 185,000 customers.

The new CIS system supports all of Yankee's business processes including order processing, meter reading, billing, payment processing, credit and collections and accounting functions. It also handles third-party notifications and Yankee's budget payment plan and energy assistance programs. And, in anticipation of future customer choice initiatives, the CIS will be able to handle unbundling of residential energy customers.
"This new system is strategically important to Yankee Gas and was an attractive feature to Northeast Utilities during merger talks," said Charles E. Gooley, president and CEO of Yankee Energy System, Inc., parent of Yankee Gas Services Company, in announcing the system's launch.

The first of its kind in New England, the new CIS system was modeled after a system developed by Northern Indiana Public Service Company (NIPSCO) and adapted by IBM to serve Yankee's specific customer service needs. A team of Yankee Gas employees worked side-by-side with a team from IBM for two years to prepare the system for implementation. The project included testing of all transactions that affect customers, such as the addition of new customers, turning on service, billing them a few months, letting them become delinquent, turning off their gas, sending a final bill and then paying the final bill. It also included running billing cycles for different types of customers (e.g. residential, commercial, industrial and firm transportation) and producing test billing statements for all Yankee customers.

In addition, Yankee installed a new supervisory control and data acquisition (SCADA) system to monitor natural gas flows and pressures within gas mains.

On the West Coast, one of the most significant Y2K-related risks facing Portland, Or-based NW Natural was rendering timely bills to its industrial and large commercial customers. In response, the company developed a new billing system for these valued customers to replace a legacy system that was not Y2K-compliant.

During development of the new I&C system, NW Natural renovated code in the legacy

billing system so that it could be operated into 2000, if necessary. That contingency plan carried the company into mid-November, when the I&C replacement project was scheduled to be implemented. NW Natural also installed a new customer information system for residential and commercial customers.

In preparation for Year 2000, the distribution segment of the Columbia Energy Group made several upgrades to its IT hardware platform and enhancements to many of its application systems. However, the prevalent "silver lining" that the five Columbia LDCs encountered in their Y2K project was in the development and testing of Y2K contingency plans, company officials say. Like many other natural gas distributors, Columbia had introduced computer and automation technologies to systems that had previously operated manually and mechanically. While enhancing efficiency, such computerization prompted concerns about Y2K issues.
Y2K provided an opportunity for staff at Columbia's natural gas distribution companies to understand, review, assess and refine existing operating and disaster recovery procedures. With the pace of today's technology advances, such review and assessment is an ongoing aspect of operational readiness.

To further test the LDCs' state of preparedness and readiness, Columbia conducted several mock drills, developed specifically to test its ability to conduct business using the identified workarounds. By participating in these drills, Columbia believes it successfully tested the effectiveness of its Y2K contingency plans and the capabilities of its personnel.
Contingency planning efforts also led to system upgrades. Consolidated Natural Gas added electric generators or improved existing generators so that the company can generate its own power if it is needed to run critical gas delivery systems. Generators can also provide power to CNG's microwave telecommunications system, and CNG will have radios and satellite communication systems available as additional communications backups.
Improved communication with customers was another benefit of Year 2000 preparations, according to a number of LDCs. Philadelphia-based PECO Energy said Y2K provided an opportunity to reach out to key audiences and improve the company's relationships with customers, elected officials and industry colleagues. PECO Energy Distribution completed its Y2K project more than six months ahead of schedule, enabling its employees to undertake projects within local communities. The company inspected more than 350 customer sites to perform assessments and other feedback on their equipment.

"Customer outreach was always an important aspect of this project," said Bob Farrington, PECO Energy Embedded Technology Manager. ***P&GJ***

Return to Top of Page

Return to archive menu

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO
RECORD REQUESTS FROM THE D.T.E.
D.T.E. 05-27

Date: August 9, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

RR-DTE-122: Please provide intra-class bill impacts for the R-1 and R-3 rate classes based on the rate redesign sought in AG-9-18, by re-running the schedules shown on Schedule JAF-2-6 for these two classes.

Response: Please see Attachment RR-DTE-122 for the bill impacts of the R-1 and R-3 classes reflecting the flat volumetric rate design requested in AG-9-18. As compared to the bill impacts presented in Schedule JAF-2-6, pages 1 and 3, the flat rate design results in bill impacts for both classes that are lower for annual usage levels less than the level at the 75th percentile strata and greater impacts above the 75th percentile strata.

Bay State Gas Company
Resdential Non-Heating Bill Impact (R/T-1)

Annual	Average Therms			Current Bill			Proposed Bill			Percent Change			$ Change	% of
Therms	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual	Per Month	Bills
0	0	0	0	$45	$45	$90	$70	$70	$139	55.50%	55.50%	55.50%	$4.14	0.00%
50	33	15	48	$88	$64	$152	$107	$87	$194	21.86%	35.16%	27.46%	$3.48	8.07%
85	**37**	**29**	**66**	**$95**	**$81**	**$175**	**$113**	**$101**	**$214**	**19.45%**	**25.40%**	**22.19%**	**$3.25**	**24.43%**
110	53	44	97	$114	$101	$216	$130	$119	$250	13.89%	17.81%	15.73%	$2.83	33.61%
140	68	57	125	$133	$119	$252	$146	$135	$282	10.28%	13.48%	11.80%	$2.48	44.00%
160	**83**	**67**	**150**	**$152**	**$130**	**$282**	**$164**	**$145**	**$309**	**7.67%**	**11.60%**	**9.49%**	**$2.23**	**50.33%**
200	100	79	179	$176	$146	$322	$185	$160	$345	5.40%	9.78%	7.39%	$1.98	62.02%
260	**132**	**97**	**229**	**$213**	**$165**	**$379**	**$220**	**$178**	**$398**	**2.91%**	**8.00%**	**5.13%**	**$1.62**	**76.07%**
300	163	117	279	$252	$190	$443	$255	$202	$457	1.11%	6.22%	3.31%	$1.22	82.80%
340	191	129	319	$289	$205	$493	$288	$216	$504	-0.13%	5.40%	2.16%	$0.89	87.83%
525	253	156	410	$367	$237	$604	$359	$246	$606	-1.96%	3.91%	0.34%	$0.17	97.36%
640	360	213	574	$502	$308	$810	$483	$313	$796	-3.79%	1.75%	-1.69%	-$1.14	98.75%
750	419	268	687	$574	$371	$945	$548	$373	$922	-4.41%	0.51%	-2.48%	-$1.95	99.36%
925	520	302	822	$700	$412	$1,112	$664	$412	$1,076	-5.19%	-0.09%	-3.30%	-$3.06	99.76%
1,025	524	450	974	$707	$588	$1,295	$670	$578	$1,248	-5.23%	-1.71%	-3.63%	-$3.91	99.82%
1,075	466	577	1,043	$634	$743	$1,377	$603	$724	$1,328	-4.82%	-2.50%	-3.57%	-$4.09	99.86%
1,200	779	367	1,146	$1,027	$490	$1,517	$962	$485	$1,447	-6.32%	-0.95%	-4.59%	-$5.80	99.89%
1,250	238	993	1,231	$348	$1,240	$1,588	$342	$1,194	$1,537	-1.59%	-3.70%	-3.24%	-$4.29	99.91%
1,350	53	1,235	1,288	$113	$1,530	$1,644	$130	$1,469	$1,599	15.02%	-4.04%	-2.73%	-$3.73	99.92%
1,750	381	1,138	1,519	$525	$1,414	$1,939	$505	$1,359	$1,864	-3.90%	-3.92%	-3.91%	-$6.33	99.95%
2,100	1,174	697	1,871	$1,521	$886	$2,407	$1,413	$859	$2,272	-7.11%	-2.98%	-5.59%	-$11.21	99.97%
2,750	2,203	176	2,380	$2,813	$257	$3,069	$2,593	$269	$2,862	-7.82%	4.82%	-6.76%	-$17.29	99.98%
4,000	1,736	1,518	3,254	$2,226	$1,870	$4,096	$2,058	$1,789	$3,847	-7.57%	-4.30%	-6.08%	-$20.75	99.98%
6,000	3,301	1,185	4,486	$4,191	$1,470	$5,662	$3,850	$1,412	$5,262	-8.14%	-3.98%	-7.06%	-$33.30	100.00%

Bay State Gas Company
Resdential Heating Bill Impact (R/T-3)

Annual	Average Therms			Current Bill			Proposed Bill			Percent Change			$ Change	% of
Therms	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual	Per Month	Bills
0	0	0	0	$45	$45	$90	$73	$73	$145	61.98%	61.98%	61.98%	$4.63	0.00%
50	0	0	0	$45	$45	$90	$73	$73	$145	61.98%	61.98%	61.98%	$4.63	0.00%
85	61	7	68	$130	$54	$184	$151	$82	$233	15.61%	52.20%	26.35%	$4.05	0.69%
110	85	11	96	$162	$58	$220	$179	$86	$266	10.85%	49.34%	20.95%	$3.83	1.12%
140	106	19	125	$192	$68	$260	$207	$97	$304	7.76%	42.53%	16.85%	$3.66	1.57%
160	125	25	150	$217	$74	$291	$230	$103	$333	5.88%	39.58%	14.44%	$3.50	1.86%
200	148	32	180	$250	$82	$332	$260	$112	$372	3.95%	36.16%	11.90%	$3.29	2.49%
260	186	46	232	$302	$97	$400	$308	$127	$435	1.76%	31.31%	8.94%	$2.98	3.67%
300	222	59	281	$351	$112	$463	$352	$143	$495	0.32%	27.77%	6.97%	$2.69	4.66%
340	250	71	321	$388	$127	$515	$386	$159	$545	-0.55%	25.07%	5.78%	$2.48	5.80%
525	350	90	440	$526	$151	$676	$511	$184	$695	-2.69%	21.98%	2.80%	$1.58	12.93%
640	472	113	585	$691	$176	$867	$666	$210	$877	-3.55%	19.56%	1.15%	$0.83	19.33%
750	**564**	**132**	**697**	**$806**	**$199**	**$1,005**	**$782**	**$235**	**$1,017**	**-2.98%**	**18.11%**	**1.19%**	**$1.00**	**27.38%**
925	684	155	839	$953	$225	$1,178	$933	$263	$1,196	-2.13%	16.87%	1.49%	$1.47	42.25%
1,025	**797**	**178**	**975**	**$1,091**	**$250**	**$1,341**	**$1,075**	**$290**	**$1,365**	**-1.52%**	**16.04%**	**1.75%**	**$1.95**	**50.95%**
1,075	859	191	1,050	$1,167	$265	$1,433	$1,154	$307	$1,461	-1.15%	15.57%	1.95%	$2.33	55.14%
1,200	932	204	1,136	$1,253	$280	$1,533	$1,245	$323	$1,567	-0.70%	15.22%	2.21%	$2.82	64.64%
1,250	1,008	216	1,225	$1,343	$293	$1,637	$1,340	$337	$1,677	-0.24%	14.93%	2.48%	$3.38	68.10%
1,350	**1,070**	**229**	**1,299**	**$1,418**	**$307**	**$1,725**	**$1,419**	**$352**	**$1,771**	**0.09%**	**14.65%**	**2.68%**	**$3.85**	**74.23%**
1,750	1,255	266	1,521	$1,637	$348	$1,985	$1,652	$397	$2,049	0.89%	14.16%	3.22%	$5.32	89.60%
2,100	1,571	330	1,901	$2,010	$418	$2,428	$2,047	$475	$2,522	1.86%	13.68%	3.89%	$7.87	95.29%
2,750	1,918	427	2,346	$2,423	$524	$2,947	$2,486	$593	$3,079	2.58%	13.24%	4.48%	$10.99	98.66%
4,000	2,486	676	3,162	$3,095	$796	$3,892	$3,199	$897	$4,096	3.34%	12.65%	5.25%	$17.02	99.77%
6,000	3,385	1,279	4,663	$4,160	$1,455	$5,614	$4,328	$1,631	$5,959	4.05%	12.14%	6.15%	$28.75	99.96%
6,600	4,440	1,754	6,194	$5,410	$1,977	$7,387	$5,655	$2,213	$7,868	4.52%	11.98%	6.52%	$40.12	99.97%
8,500	5,098	2,285	7,384	$6,191	$2,556	$8,747	$6,483	$2,860	$9,343	4.72%	11.88%	6.81%	$49.65	99.99%
9,500	6,799	2,384	9,184	$8,207	$2,666	$10,873	$8,622	$2,982	$11,604	5.06%	11.86%	6.73%	$60.94	99.99%
12,000	7,704	3,220	10,923	$9,280	$3,579	$12,859	$9,760	$4,000	$13,761	5.18%	11.77%	7.01%	$75.16	100.00%
15,000	11,509	2,216	13,725	$13,790	$2,482	$16,271	$14,545	$2,777	$17,322	5.48%	11.89%	6.46%	$87.54	100.00%
30,000	15,639	2,607	18,246	$18,685	$2,911	$21,595	$19,739	$3,255	$22,994	5.64%	11.83%	6.48%	$116.53	100.00%
47,000														
50,000														
60,000														
70,000														
90,000	60,266	18,356	78,623	$71,581	$20,135	$91,716	$75,860	$22,464	$98,323	5.98%	11.57%	7.20%	$550.65	100.00%